

## Comment Report

**Project Name:** 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 4  
**Comment Period Start Date:** 8/28/2024  
**Comment Period End Date:** 9/13/2024  
**Associated Ballots:** 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 4  
OT  
2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 4 ST

There were 45 sets of responses, including comments from approximately 129 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

## **Questions**

**1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.**

**2. Provide any additional comments for the Drafting Team to consider, if desired.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Performance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO

					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC

David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
Joel Charlebois	AESI	7	NPCC
John Hastings	National Grid	1	NPCC
Erin Wilson	NB Power	1	NPCC
James Grant	NYISO	2	NPCC

					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

**Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter**

**Answer** No

**Document Name**

**Comment**

FE sees no alternative or more cost-effective options.

Likes 0

Dislikes 0

**Response**

**Marcus Bortman - APS - Arizona Public Service Co. - 6**

**Answer** No

**Document Name**

**Comment**

None

Likes 0

Dislikes 0

**Response**

**Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF**

**Answer** No

**Document Name**

**Comment**

Duke Energy does not normally respond to cost-effective questions and offers no alternatives to what has been proposed in PRC-030-1.

Likes 0

Dislikes 0

**Response**

**Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group**

**Answer** No

**Document Name**

**Comment**

WEC Energy Group supports the comments of the MRO NSRF and the NAGF.

Likes 0

Dislikes 0

**Response**

**Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable**

**Answer** No

**Document Name**

**Comment**

EEl offers no alternatives to what has been proposed in PRC-030-1.

Likes 0

Dislikes 0

**Response**

**Glen Farmer - Avista - Avista Corporation - 5**

**Answer** No

**Document Name**

**Comment**

EEl offers no alternatives to what has been proposed in PRC-030-1

Likes 0

Dislikes 0

**Response**

**Selene Willis - Edison International - Southern California Edison Company - 5**

Answer	No
Document Name	
<b>Comment</b>	
Please see "EEI Comments"	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle</b>	
Answer	No
Document Name	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Donna Wood - Tri-State G and T Association, Inc. - 1</b>	
Answer	No
Document Name	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez</b>	
Answer	No
Document Name	
<b>Comment</b>	

Likes 0

Dislikes 0

**Response**

**Kevin Conway - Western Power Pool - 4**

**Answer**

No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers**

**Answer**

No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Fong Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC**

**Answer**

No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Jessica Cordero - Unisource - Tucson Electric Power Co. - 1**

**Answer** No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Mike Magruder - Avista - Avista Corporation - 1**

**Answer** No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Amy Wilke - American Transmission Company, LLC - 1**

**Answer** No

**Document Name**

**Comment**

Likes 0

Dislikes 0

**Response**

**Brian Lindsey - Entergy - 1**

**Answer** Yes

**Document Name**

**Comment**

A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data.

Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.

Likes 0

Dislikes 0

**Response**

**Marty Hostler - Northern California Power Agency - 3,4,5,6**

**Answer**

Yes

**Document Name**

**Comment**

The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective to address recommendations of FERC order 901 or if, or to what extent, this proposal will improve reliability.

Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data.

Likes 0

Dislikes 0

**Response**

**Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group**

**Answer**

Yes

**Document Name**

**Comment**

The MRO NSRF does agree that inverter-based resources need identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.
- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “...and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, changes in Real Power for the following are excluded:

- Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing;
- A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
- Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

1.1.1. Determine the root cause(s) of change(s) in Real Power output;

1.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

1.1.3. Assess any performance issues identified and if corrective actions are needed; and

1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Likes 1

JEA, 1, McClung Joseph

Dislikes 0

**Response**

**Ruchi Shah - AES - AES Corporation - 5**

**Answer** Yes

**Document Name**

**Comment**

GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.

Likes 0

Dislikes 0

**Response**

**George E Brown - Pattern Operators LP - 5**

**Answer** Yes

**Document Name**

**Comment**

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0

Dislikes 0

**Response**

**Kimberly Turco - Constellation - 6**

**Answer** Yes

**Document Name**

**Comment**

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0

Dislikes 0

**Response**

**Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples**

**Answer** Yes

**Document Name**

**Comment**

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1.

Likes 0

Dislikes 0

**Response**

**Hillary Creurer - Allete - Minnesota Power, Inc. - 1**

**Answer** Yes

**Document Name**

**Comment**

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0

Dislikes 0

**Response**

**Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF**

**Answer** Yes

**Document Name**

**Comment**

*GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.*

Likes 0

Dislikes 0

**Response**

Answer Yes

Document Name

Comment

PNM agrees with the comments of MRO:

The MRO NSRF does agree that inverter-based resources need identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

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is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

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- Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

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1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Likes 0

Dislikes 0

## Response

**Michael Goggin - Grid Strategies LLC - 5**

**Answer**

Yes

**Document Name**

**Comment**

We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in output that are larger than this threshold.<sup>[1]</sup> As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.<sup>[2]</sup> As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, “If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage.”<sup>[3]</sup>

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve.<sup>[4]</sup> In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

## Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to “Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

<sup>[C]{1}{C}</sup> <https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144>

<sup>[C]{2}</sup> <https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282>, at 6

<sup>[C]{3}{C}</sup> <https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf>, at 29

[\[C\]4](https://link.springer.com/article/10.1007/s40565-019-0535-4) See Figure 4 for an example of a synchronous generator's P-Q curve and Figure 5 for a non-synchronous generator's P-Q curve:  
<https://link.springer.com/article/10.1007/s40565-019-0535-4>

Likes 0

Dislikes 0

### Response

#### Colin Chilcoat - Invenergy LLC - 6

Answer

Yes

Document Name

### Comment

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.

Likes 0

Dislikes 0

### Response

#### Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer

Yes

Document Name

### Comment

*GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.*

Likes 0

Dislikes 0

### Response

#### Rhonda Jones - Invenergy LLC - 5

Answer

Yes

Document Name

### Comment

*PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.*

Likes 0

Dislikes 0

## Response

**Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators**

**Answer**

Yes

**Document Name**

**Comment**

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase "implement a documented process to" from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period. Changes in Real Power for the following are excluded:

- Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing;
- A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the removal of the word "identifying" from Requirement R2. It is the opinion of ACES that removing this word places an undue burden on the GO to perform the analysis within an unnecessarily compressed timeline. While it is still our opinion that a timeline of 120 days is more appropriate as it is more consistent with PRC-004-6; we do not see it as an insurmountable hurdle to require a 90 calendar-day timeline so long as it begins when the GO identifies the event. Thus, we recommend modifying R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 90 calendar days, of either:

- identifying a Real Power change event pursuant to Requirement R1 or,
- receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and likely the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt (or even acknowledge receipt)? In short, if the RC, BA, or TOP desires an opportunity to review the CAP(s) developed by the GO, there is already a mechanism in place for this via the documented data specification(s).

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend modifying these sections so that they are inline with one another. In other words, either require the GO to notify the RC, BA, and TOP in R4 Part 4.3 or remove the BA and TOP from Requirement R3.

Likes 0

Dislikes 0

### Response

**Dwanique Spiller - Berkshire Hathaway - NV Energy - 5**

**Answer**

Yes

**Document Name**

**Comment**

Likes 0

Dislikes 0

### Response

**Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO**

**Answer**

Yes

**Document Name**

**Comment**

Likes 0

Dislikes 0

### Response

**Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring**

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
No Comment	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
ITC has no comment.	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3</b>	
<b>Answer</b>	
<b>Document Name</b>	

**Comment**

No comment on cost effectiveness.

Likes 0

Dislikes 0

**Response**

**2. Provide any additional comments for the Drafting Team to consider, if desired.**

**Amy Wilke - American Transmission Company, LLC - 1**

**Answer**

**Document Name**

**Comment**

ATC had not initially joined the ballot pool for this standard as it was not directly applicable to TO/TOP, however, we would like to express our support of the standard as written and thank the team for their effort.

Likes 0

Dislikes 0

**Response**

**Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators**

**Answer**

**Document Name**

**Comment**

Thank you for the opportunity to comment.

Likes 0

Dislikes 0

**Response**

**Patricia Lynch - NRG - NRG Energy, Inc. - 5,6**

**Answer**

**Document Name**

**Comment**

NRG is in alignment with NAGF's comments

Likes 0

Dislikes 0

**Response**

**Usama Tahir - Seminole Electric Cooperative, Inc. - 3**

Answer

Document Name

Comment

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would the Generator Owner still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event. ]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0

Dislikes 0

Response

**Constantin Chitescu - Ontario Power Generation Inc. - 5**

Answer

Document Name

Comment

OPG supports NPCC Regional Standards Committee's comments.

Likes 0

Dislikes 0

Response

**Bret Galbraith - Seminole Electric Cooperative, Inc. - 6**

Answer

Document Name

Comment

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?

2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would Seminole still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event. ]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0

Dislikes 0

**Response**

**Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC**

**Answer**

**Document Name**

**Comment**

NPCC RSC supports the Project.

Likes 0

Dislikes 0

**Response**

**Colin Chilcoat - Invenergy LLC - 6**

**Answer**

**Document Name**

**Comment**

Thank you for the opportunity to provide comments.

Likes 0

Dislikes 0

**Response**

**Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2**

**Answer**

Document Name

Comment

ERCOT supports modifying the criteria in Requirement R1 to 20 MW **OR** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be “&bull; A Transmission or collection system loss that, **through normal clearing**, disconnects the IBR generator;” which would better align with the language used in other locations in the standards that describe normal clearing of faults.

ERCOT recommends that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, and TO within three business days of the identification of an event. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations.

Finally, in light of FERC’s directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC’s Order is provided below (emphasis added).

33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any “technical, commercial, or operational constraints” that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 **does not define “technical, commercial, or operational constraints,” leaving those terms open to interpretation by each generator owner.** In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but **expressed concern with the uncertainties, ambiguities, and vagueness of the Standard’s descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements.** Thus, the **Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan.**

Likes 0

Dislikes 0

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Fong Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p>SMUD appreciates the Standard Drafting Team's actions to change the Section 4, Applicability language to match that in the proposed PRC-028-1 and PRC-030-1 reliability standards. Although time is short to make further changes, the following improvements should be considered by this Standard Drafting Team or a future Team to enhance PRC-030-1.</p> <p>1) PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. The exclusionary bullet four assumes that a Misoperation has occurred and does not leave room for correct operations of protection systems. This would create an unnecessary burden on registered entities to create compliance documentation for both PRC-004 and PRC-030 for the same event caused by the correct operation of a protection system. We agree with the recommendation provided by the MRO NSRF to revise the bullet four language to the following and remove the overlap:</p> <p>“Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.”</p> <p>2) PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. SMUD does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.</p>	
Likes 0	
Dislikes 0	

**Response**

**Patricia Ireland - DTE Energy - 4, Group Name DTE Energy**

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p>The PRC-030 standard language (Applicability Section 4.2.2) needs to align to Project 2020-06 for defining the term that will represent Category 2 IBRs</p> <p>Similarly, the PRC-030 Implementation plan (footnote 8 on page 3 and the term definition for "applicable non-BES IBRs" used on Page 4) needs to align to Project 2020-06 definition of the Category 2 BES</p>	
Likes 0	
Dislikes 0	

**Response**

**Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC**

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	

Kindly suggest greater consideration of the standard drafting team to take in consideration therecommendations made by OEM and GO/GOP of existing IBRs on capabilities vs reliabiliaty improvement vs cost, from previous and current commenting.

Likes 0

Dislikes 0

### Response

**Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez**

Answer

Document Name

### Comment

SRP supports the standard but would like to see the 90 day portion of R2 reduced to 7 days. In order to ensure impacts to the BES are minimized, it seems important to define root causes to determine if an IBR can be safely returned to service or if mitigations need to be prepared if returned to service, or if the IBR needs to be kept on forced outage until mitigated. As we become more and more dependent on this type of resource for load serving and regulating needs this level of urgency is warranted in our opinion.

Likes 0

Dislikes 0

### Response

**Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3**

Answer

Document Name

### Comment

R1 requirements

The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output ? in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given ? across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.

R2 & R3 requirements

The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.

The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is

that: "The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity". Additionally it is stated that: "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed"

The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.

Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.

The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0

Dislikes 0

### Response

**Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group**

**Answer**

**Document Name**

**Comment**

WEC Energy Group supports the comments of the MRO NSRF and the NAGF.

Likes 0

Dislikes 0

### Response

**Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF**

**Answer**

**Document Name**

**Comment**

*The NAGF has identified several concerns regarding the proposed revisions:*

- 1. Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.*
- 2. Inconsistency between R3 and R4: R3 requires the Corrective Action Plan (CAP) to be provided to the RC, BA, and TOP, while R4 only mentions the RC. This inconsistency was noted as potentially problematic.*

3. *VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.*
4. *Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.*
5. *Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.*

Likes 0

Dislikes 0

### Response

**Kimberly Turco - Constellation - 6**

**Answer**

**Document Name**

**Comment**

Constellation thinks "Nameplate rating" needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend adding "at the Point of Interconnection as defined in the interconnection agreement" in R1. Further, although the analysis completion was changed from 45 days to 90 days in R1. Timeframe needs to be adjusted to 120 days to match PRC-004 .

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0

Dislikes 0

### Response

**Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF**

**Answer**

**Document Name**

**Comment**

Duke Energy agrees with and suggest implementation of NAGF comments #1, #3 and #4 identified below:

#1: Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.

#3: VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.

#4: Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.

Additionally, Duke Energy notes that PRC-030 is dependent on data from PRC-028.

Likes 0

Dislikes 0

### Response

**Rachel Schuldt - Black Hills Corporation - 6, Group Name** Black Hills Corporation - All Segments

**Answer**

**Document Name**

**Comment**

Black Hills Corporation agrees with and supports NAGF comments.

In addition, Black Hills Corporation is concerned with the standard not defining a time frame for RC, BA, or TO to notify GO of a disturbance. Black Hills Corporation's current practice is to maintain a rolling year's worth of data, it is unclear if this would be sufficient for compliance with the standard.

Likes 0

Dislikes 0

### Response

**Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO**

**Answer**

**Document Name**

**Comment**

1) Shouldn't another bullet be added in the exclusion list in R1?

· Real Power reduction due solely to a RAS (Remedial Action Scheme) Misoperations being analyzed and corrected under PRC-012 Reliability Standard

Likes 0

Dislikes 0

### Response

**Ruchi Shah - AES - AES Corporation - 5**

**Answer**

**Document Name**

**Comment**

Substantive change in R2 - Standard (1st screenshot) has been updated to remove “identifying” from R2. By making this change the 90 day timeline is effectively shortened during which entities have to analyze the event, because entities will not be able to “identify” events in real time.

Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.

Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.

Likes 0

Dislikes 0

**Response**

**Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group**

**Answer**

**Document Name**

**Comment**

The MRO NSRF thanks the SDT for consideration of these and previous comments.

Likes 0

Dislikes 0

**Response**

**Marty Hostler - Northern California Power Agency - 3,4,5,6**

**Answer**

**Document Name**

**Comment**

If BAs, RCs, and TOPs needed this data then they have had years to request it via their interconnection agreements and market rules.

Likes 0

Dislikes 0

**Response**

**Donna Wood - Tri-State G and T Association, Inc. - 1**

**Answer**

**Document Name**

**Comment**

N/A

Likes 0

Dislikes 0

**Response**

**Marcus Bortman - APS - Arizona Public Service Co. - 6**

**Answer**

**Document Name**

**Comment**

None

Likes 0

Dislikes 0

**Response**

**Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC**

**Answer**

**Document Name**

**Comment**

Requirement R3 mandates that all CAPs or justifications from “performance issues and corrective actions [that] were identified in Requirement R2 Part 2.1.3” be provided “to the applicable RC, BA, and TOP”. However, not all issues and actions from Requirement R2 were identified or communicated to the GO from the RC, BA, or TOP. As such, only the ones coming from the RC, BA, or TOP should have to be provided back to them and then, only to the one(s) that provided it to the GO, not necessarily to all three.

Similar comment to Requirement R4.3 - only the CAP actions resulting from a notification from the RC should have to be reported back to the RC. Also, what about the CAP actions resulting from a BA or TOP notification - shouldn't they be communicated back to them?

Likes 0

Dislikes 0

**Response**

**Thomas Foltz - AEP - 5**

**Answer**

**Document Name**

**Comment**

AEP would like to thank the SDT for revising R2 to make it clear that the expectations are within 90 days of the event itself, and for replacing the word “applicable” with “associated” throughout the standard in regards to the Functional Entities.

On the previous ballot period, the SDT responded to AEP by stating “In the case where a root cause cannot be identified, this would conclude the analysis portion of Requirement R2. However, **\*mitigating actions should be implemented\*** so that a root cause can be determined for subsequent events, such as correcting inverter logs and insufficient data capture.” While AEP agrees in principle that doing so would be a reasonable approach, we do not believe the standard obligations themselves clearly convey such expectations, as this language is not included in the standard nor insight provided within the Technical Rationale. This language needs to be explicitly included in the standard, so that it is fully understood and consistently executed by Functional Entities. In addition, the standard could be further improved by revising it to accommodate for situations when a cause is found, but where an entity is unable to fully mitigate it.

Likes 0

Dislikes 0

**Response**

**Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter**

**Answer**

**Document Name**

**Comment**

FirstEnergy continues to request clarification on the determination of what would be a failure vs. weather as related to Requirement 1. FirstEnergy would request an expansion of the threshold criteria that would fall under PRC-030-1, understanding the scan rate is able to detect these changes, these minor occurrences and investigations potentially take the primary focus away from the protection of the BES.

Likes 0

Dislikes 0

**Response**

**Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring**

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p>WECC voted affirmative but offers the following for consideration.</p> <p>Standard comments- Consider spelling out Inverter-Based Resource in the third bullet of Requirement 1 that currently is just “IBR” to be consistent with other Requirements. Consider capitalizing “inverter-based resource” in Requirement R2 Severe VSL. Requirement R3 Lower, Moderate, and High VSLs need to reflect “calendar days” to match the Requirement language (and the Severe VSL language)</p> <p>Implementation Plan comments-The title of Standard PRC-029 is not correct (should be “PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources”). In the “Background” section first sentence there is a need to update “inverter-based resources (IBR)” and replace the added “Inverter-Based Resources (IBR)” with simply “IBRs”. Determine if a hyphen is needed or not for “BPS-connected” as both are used. Need to lower case the “s” in “IBRS” in the last sentence of “General Considerations”. Footnote 8 needs edited to remove the first “as” between “such” and “IBRs”. Need to lower case the “s” in “IBRS” in the sentence under “Bulk-Electric System IBRs” header. Although allowed, consider consistency in use of “Bulk Electric System” or “Bulk-Electric System” especially when sitting next to each other in document. Suggest simply use “BES IBRs” as the header and the first part of sentence under the “Bulk-Electric System IBRs” header. Consider removal of “Applicable” for the “Applicable Non-BES IBRs” header as it is unnecessary. The definition provides what a Non-BES IBR may be and a Standard would determine the applicability. If the DT thinks “applicable” is necessary, why is it not a modifier for “Bulk-Electric System IBRs” section?</p> <p>It is not clear what the last sentence under the header “Applicable Non-BES IBRs” provides. Note the first part of the sentence (if retained as is) needs corrected to “Applicable Non-BES Inverter-Based Resources.” It should be noted within the Implementation Plan and/or Technical Rationale that the Non-BES IBR definition reflects the ROP definition for Category 2 (and does not capitalize “inverter-based resource”.) Now, with the “Applicable” modifier, the sentence reads as if there <b>are more</b> Non-BES Inverter-Based Resources that are included in the Phased-in Compliance considerations. Suggest removal of “Applicable” and the last sentence. If not, then the DT needs to explain what other “Applicable Non-BES IBRs” are outside of the defined Non-BES IBRs. There is a SAR that is considering “IBR-DER”, “Sub-BES IBR”, and “Non-Material IBR” definitions but that is in early stages of consensus building.</p>	
Likes 0	
Dislikes 0	
<b>Response</b>	
<b>Brian Lindsey - Entergy - 1</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p><b>Implementation Plan:</b></p> <p>This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet.</p>	

The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.

**Requirements:**

R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis.

Concerns with having to provide the information to multiple entities.

R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities?

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

Likes	0
Dislikes	0
<b>Response</b>	